NRDC

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Department of Conservation
801 K Street, MS 24-02
Sacramento, CA 95814
ATTN: UIC Discussion Draft

Submitted electronically via: UIC.Regulations@conservation.ca.gov

On behalf of the Natural Resources Defense Council ("NRDC"), which has 2.4 million members and activists, more than 380,000 of whom are Californians, we write to submit comments on the Updated Underground Injection Control Regulations Pre-Rulemaking Discussion Draft.

Respectfully submitted,

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GENERAL COMMENTS

A complete overhaul of California's Underground Injection Control (UIC) Program is critically needed to ensure that injection does not endanger Underground Sources of Drinking Water (USDWs) and to protect the environment and public health and safety. Internal and external audits, including the 2011 Horsley Witten Report (Horsley Witten Group, 2011), the 2015 CalEPA Review of the UIC Program (California Environmental Protection Agency, 2015), and the 2015 SB855 Report (California Division of Oil, Gas, and Geothermal Resources, 2015) have revealed deep, systemic flaws in the program. Recent events such as the disastrous leak at the Aliso Canyon underground natural gas storage facility and revelations that the Division of Oil, Gas, and Geothermal Resources (the Division) improperly permitted more than 2,500 wells to inject into non-exempt aquifers starkly illustrate the real consequences of those flaws. The rebuilding of California's UIC program is long overdue, and we look forward to working with the Division to modernize its regulations and ensure those rules fulfil the Division's mandate to prevent damage to life, health, property, and natural resources.

Missing Topics

In its "Discussion Paper for Workshops on the Development of Updates to DOGGR's Underground Injection Control Regulations," the Division identified six regulatory "goals." Three of those six goals:

1. REGULATORY GOAL #3: Codify best practices for well construction
2. REGULATORY GOAL #4: Establish permitting and regulatory requirements specific to cyclic steam operations
3. REGULATORY GOAL #5: Establish requirements specific to cyclic steam in diatomite, including a regulatory framework for responding to surface expressions and clarification regarding injection above fracture gradient

are not addressed in the current Pre-Rulemaking Discussion Draft. We request that the Division clarify the timeline for addressing these topics and that pre-rulemaking discussion drafts of these topics be released prior to any official rulemaking.

Project Approval Letter vs. Notice of Intent

We request that the Division clarify the relationship between the Project Approval Letter (PAL) and individual injection well permits. Specifically, we request that the Division require that individual permits be evaluated based on the information in the PAL, to ensure consistent standards are applied across the injection project and individual well permit approvals are based on comprehensive data about the injection project.

The Division should also clarify the sequence in which these approvals must occur – in other words, must an injection project have a PAL before individual permits can be granted, or vice versa? Section 1724.6(a) states that, "[a] Project Approval Letter shall be obtained from this the Division before any injection occurs *as part of an underground injection project*" (emphasis added). This implies that injection may be possible without a PAL if it is not part of an underground injection project. We request that the Division clarify the intent of this provision.

SPECIFIC COMMENTS

1720.1. Definitions

(a) "Area of Review"

The Division's proposed definition of and method for determining the Area of Review (AoR) is insufficient to protect USDWs. While we support the Division's proposal to require greater reliance on the Zone of Endangering Influence (ZEI) concept from federal Class II rules as opposed to a fixed radius, more sophisticated modeling should be required, particularly given the wide range of injection activities that occur in California.

The method for determining the AoR should be tailored to the specific type of injection operation. Injection activities occurring in California include disposal; Enhanced Oil Recovery (EOR) operations such as waterflooding, steam flooding, and cyclic steam; and gas storage operations, among others. These different types of injection projects each have unique engineering challenges and may pose unique environmental threats. For example, disposal projects inject fluids for permanent storage without withdrawing fluids, which may increase the formation pressure over time whereas in EOR projects like waterflooding and steam flooding, both injection and withdrawal is occurring from the same formation, which may help balance pressure. Cyclic steam projects and underground gas storage projects use the same wells to both inject and withdraw fluids, whereas disposal and waterflood or steam flood projects are more likely to use dedicated injectors. These operational differences present different threats to USDWs, and should be reflected in the methodologies for determining the AoR for different types of injection projects.

The proposed method, which relies only on pressure in the injection zone to determine the AoR, is not adequate. Many factors beyond injection zone pressure must be assessed to determine whether injection fluid or formation fluid may migrate out of the intended zone of injection, including the porosity and permeability of the injection and confining formations; rock mechanical properties; hydraulic gradient; injection rate; physical and chemical properties of the injectate; and others. The AoR should be informed by and consistent with the engineering and geologic study required by proposed section 1724.7(a)(1).

The area of review should be the region around an injection well or group of injection wells where USDWs may be endangered by the injection activity. It should be delineated based on 3D geologic and reservoir computational modeling that accounts for the physical and chemical properties and extent of injected fluids and displaced formation fluids and be based on the life of the project. The physical extent would be defined by the modeled horizontal and vertical penetration of injected fluids, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time.

The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated injection pressures, rates, and volumes.
2. Geologic and engineering heterogeneities
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations.
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model should be updated and history matched. Operators should develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation.

The Division has not provided any justification for the selection of 300 feet as the minimum AoR for cyclic steam wells, versus a quarter mile for all other types of injection projects. The Division should explain why this smaller radius is appropriate and the rationale for selecting this value.

(d) "Freshwater"
The 2011 Horsley Witten Group review of California's UIC program highlighted a number of issues, among them the concern that Underground Sources of Drinking Water (USDWs) containing more than 3,000 milligrams per (mg/L) total dissolved solids (TDS) are not fully protected under the California UIC regulations due to California's

use of the term "fresh water," which has been used to describe groundwater that contains 3,000 liter mg/L or less TDS. (Horsley Witten Group, 2011) The proposed rules would address this issue by adding a definition of USDW and updating key regulations to ensure protection of USDWs. As such, it is unclear why the Division has chosen to retain the term "fresh water" in the proposed regulations. Given that "fresh water" aquifers are a subset of USDWs, retaining the term is now redundant and could lead to confusion and therefore we recommend that the Division delete the term from its proposed regulations.

(e) "Underground injection project"
The Division's proposed definition of "underground injection project" contains the vague and undefined terms "sustained or continual injection" and "extended period." This vagueness invites abuse and may exclude key underground injection activities. For example, the Division lists cyclic steam as an example of an underground injection project. However, in cyclic steam projects injection may occur for days or weeks, followed by days or weeks of production. Given the vagueness of the terms, one could argue that injection at these projects is neither "sustained/continual" nor does it occur for an "extended period," and therefore should be excluded from the definition of underground injection project. Similarly, underground gas storage projects may also inject for a period followed by a period of production.

We recommend that the Division use the same definition for "underground injection" as that used in the federal UIC regulations namely:

"Underground injection" means the subsurface emplacement of fluids through a well.[1]

(f) "Underground source of drinking water"
The Division's proposed definition for USDW is inconsistent with federal UIC program definition of USDW. Critically, aquifers that are currently in use, regardless of that aquifer's total dissolved solids content or exempt status, appear not to be included in the Division's proposed definition, in direct conflict with the federal USDW definition. We recommend that the Division use the same definition from federal UIC regulations, namely:

> "Underground source of drinking water (USDW) means an aquifer or its portion:
> (a)(1) Which supplies any public water system; or
> (2) Which contains a sufficient quantity of ground water to supply a public water system; and
> > (i) Currently supplies drinking water for human consumption; or
> > (ii) Contains fewer than 10,000 mg/l total dissolved solids; and
>
> (b) Which is not an exempted aquifer."[2]

Additional Definitions Needed
We recommend that the Division add the following terms:

"Confining Zone" means a geological formation, group of formations, or part of a formation that is capable of limiting fluid movement above an injection zone.

"Injection Zone" means a geological formation group of formations, or part of a formation receiving fluids through a well.

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[1] 40 CFR §144.3
[2] *Id.*

1724.6. Approval of Underground Injection and Disposal Projects

(a)
We request that the Division add a provision requiring the PAL process include a public comment period of no less than 60 days prior to approval, and that all materials submitted to the Division be made publicly available as part of this process. Public notice should also be given once the PAL is approved, including publication on the Division's website and notice to landowners and offset operators.

(c)
The proposed rules state that "the Division will review underground injection projects to verify adherence to the terms and conditions of the Project Approval Letter, and will periodically review the terms and conditions of the Project Approval Letter." We recommend that the Division set a fixed frequency for performing such reviews. Consistent with the Division's Manual of Instructions (MOI) and directives to the district offices, such reviews should be performed yearly. (Horsley Witten Group, 2011) Results of these reviews should be made publicly available on the Division's website.

(e)
We recommend that, in the event of a transfer of an underground injection project to a new operator, the new operator should meet with the Division staff within 15 days of transfer, rather than the proposed 60.

1724.7. Project Data Requirements

(a)
We recommend that the Division add language to this subsection to mirror the primary mission of the federal UIC program:

"An underground injection project shall be supported by data filed with the Division that demonstrates to the Division's satisfaction that injected fluid will be confined to the approved zone or zones of injection and that the underground injection project will not cause damage to life, health, property, or natural resources<u> and will not endanger drinking water sources</u>."[3]

The proposed rules state that "The operator shall ensure that the data are current and account for all changes to the setting and operation of the project." This provision is vague and we recommend that the Division set a fixed frequency for reviewing the data filed with the Division to ensure that the data are current. We recommend that this should occur no less often than once every five years, or more frequently as necessary due to material changes to the injection project including but not limited to any change to the Area of Review or the addition of new injection or monitoring wells, or when required by the Division. Operators should incorporate any new data acquired as a result of required monitoring or testing provisions (e.g. sections 1724.10 and 1724.10.1) and other pertinent data, or provide a justification for why no update is required. This revision process should also include a public comment period. Additionally, the Division should require that the data be certified by a registered Professional Engineer or Professional Geologist having personal knowledge of the facts therein.

(a)(1)(B)
The phrase "vertical interval above and below the intended reservoir" is vague and we request that the Division clarify the intent of this proposed requirement. We also recommend the following revisions and additions:

"Reservoir characteristics of each injection zone, such as porosity, permeability, average thickness, areal extent, fracture gradient, original and present temperature and pressure, and original and residual oil, gas, and water saturations. The scope of the geologic characterization shall encompass the intended reservoir rock and sealing

[3] 42 U.S.C. 300h *et seq.*

mechanisms, the vertical interval above and below the intended reservoir, areas where fluid could potentially migrate, and the areas adjacent to the intended reservoir where potential entrapment of migrated fluid could occur. Operators must submit information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:

i. Maps and cross sections of the area of review;
ii. The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;
iii. Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;
iv. Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);
v. Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and
vi. Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.

Owners and operators of injection projects must demonstrate to the satisfaction of the Division that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:

i. An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of injectate over the life of the project;
ii. Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected fluid and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
iii. The Division may require owners or operators of injection projects to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.

(a)(1)(D)
We recommend the following changes to this subsection, consistent with federal Class II requirements:

A map ~~of the area of review~~ showing ~~the location and status of all wells within and adjacent to the boundary of the area of review~~ the injection well or project area for which a permit is sought and the applicable area of review. Within the area of review, the map must show the number or name, and location of all wells, including but not limited to injection, producing, abandoned, plugged, monitoring, and permitted wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. The wellbore path of directionally drilled wells shall be shown, with indication of the interval penetrating the injection zone of the underground injection project.

(a)(1)(E) - (G)
Injection project owners/operators should be required to develop, submit, and implement a plan to:

1. Identify artificial penetrations (e.g. wells, mines) within the AoR that may become conduits for fluid movement out of the injection zone, or additional zones, and potentially cause endangerment to a USDW, and;
2. Assess such artificial penetrations and perform corrective action as necessary.

Developing unique, site-specific plans for performing this work, as opposed to using predetermined procedures, is crucial given the variety of injection project types and the age of the fields and associated infrastructure in which injection projects occur in California. These plans should be developed collaboratively between the Division and injection project operators.

Identification of Artificial Penetrations

The identification and assessment of wells (or other features) that could allow injected fluids to migrate outside the approved injection zone or otherwise endanger life, health, property, or natural resources should be required not just for wells that penetrate the injection zone but for all penetrations of the *confining zone(s)*, including but not limited to wells or mines.

The types of wells that must be identified and assessed should be expanded from just idle, plugged and abandoned, or producing to also include *all* active wells (e.g. injection, monitoring, and observation wells), inactive wells, drilling wells, permitted wells, and others.

Given California's long history of oil and gas production, locating existing wells – in particular plugged and abandoned wells – may be challenging and require the use of multiple detection methods. The following stages of investigation should be included in the artificial penetration identification plan:

1) Historical Record Review. Operators should begin by reviewing both internal and publicly available state and local records to locate abandoned/orphaned wells.
2) Site Reconnaissance. Operators should physically search for features that may be indicative of abandoned wells and interview local landowners.
3) Aerial and Satellite Imagery Review. Operators should review current and historical aerial and satellite imagery to look for features that may be indicative of abandoned wells.
4) Geophysical and Air Emissions Surveys. A geophysical survey such as magnetic, ground penetrating radar (GPR), or electromagnetic methods should be conducted to help identify abandoned wells for which surface features no longer exist or which are undocumented. An air emissions survey (e.g. for methane, VOCs) can also help identify abandoned wells that may not be detectable with geophysical methods due to the absence of steel casing. (Hammack, Veloski, & Hodges, 2006)

We also recommend the Division review *ASTM D6285-99(2012)e1, Standard Guide for Locating Abandoned Wells*, for additional guidance.

Assessing and Performing Corrective Action on Identified Wells

Once existing wells that penetrate the confining zone(s) are identified, the condition of each must be assessed and corrective action must be performed as necessary to ensure that such wells will not act as pathways for injected or displaced fluids to reach USDWs. The assessment and corrective action plan should include the following steps to evaluate each existing well:

1) Well Record Review. The records for each well in the AoR that penetrates the confining zone should be reviewed to assess the design, construction, maintenance, and, if applicable, plugging methods. The well record review should be used to identify wells that require field inspection and testing to determine mechanical integrity. If records indicate that wells were constructed or plugged using outdated methods, or if well records are incomplete or nonexistent, field inspection and testing of these wells should be performed.

2) Field Inspection and Testing. Based on the results of the records review, field inspection and testing of suspect wells should be performed. Wells should be assessed for internal and external mechanical integrity, corrosion, and integrity of cement plugs (in abandoned wells).
3) Corrective Action. Based on the results of the records review and field inspection and testing, corrective action must be performed as necessary. This may include a variety of activities depending on the deficiencies identified, including:
    a. *Reworking*: Existing active, idle, or plugged wells not designed or constructed to adequate standards must be reworked to ensure that they will not serve as pathways for injected or displaced fluids to reach USDWs. This may include remedial cementing to isolate potential flow zones and ensure external mechanical integrity; replacing or adding casing, liners, tubing, and packers to ensure internal mechanical integrity and/or remediate corrosion; and other steps as necessary to protect USDWs.
    b. *Plugging/re-plugging*: Improperly abandoned wells must be plugged or re-plugged to ensure no movement of injected or displaced fluids, including and drilling out and replacing inadequate plugs or adding additional plugs, as necessary. If reworking of active or idle wells indicates that they lack mechanical integrity and it cannot be restored, such wells must be plugged and abandoned.

In the proposed rules, subsection (a)(1)(E)(i), the Division would require operators to submit casing diagrams to demonstrate that "[p]lugged and abandoned wells have cement across all perforations and extending at least 500 feet, if shown by calculation, or 100 feet, if shown by cement bond log or other method approved by the Division, above the highest of the top of a landed liner, the uppermost perforations, the casing cementing point, the water shutoff holes, the intended zone of injection, or the oil and gas zone;." The quality of a cement plug and its adequacy to prevent the movement of fluid is not relative to how the top of the plug is determined, and we therefore request that the Division remove this proposed provision. Furthermore, the top of a cement plug is typically determined by tagging it with drill pipe or tubing; the top of cement behind casing is typically determined by a cement bond log (CBL). As such, it is not clear why the Division is proposing that the top of a cement plug should be determined by a CBL and we request clarification on this provision. We provide additional specific recommendations relating to plugging below.

In sum, we recommend the proposed language in subsections (a)(1)(E) – (G) be replaced with the following:

<u>The owner or operator of an injection project must prepare, maintain, and comply with a corrective action plan that meets the requirements of this section and is acceptable to the Division. As a part of the Project Approval Letter application process, the owner or operator must submit a plan describing how corrective action will be conducted to meet the requirements of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.</u>

<u>The following are required elements of the corrective action plan:</u>
1) <u>Identification of all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Methods considered for identifying artificial penetrations must include:</u>
    a) <u>Historical record review;</u>
    b) <u>Site Reconnaissance;</u>
    c) <u>Aerial and Satellite Imagery Review;</u>
    d) <u>Geophysical and/or Air Emissions Survey; and,</u>
    e) <u>any other methods required by the Division.</u>

2) A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion; information required under section 1724.7.1; and any additional information the Division may require
3) A process for determining which abandoned wells in the area of review have been plugged in a manner that prevents the movement of injected or displaced fluids that may endanger USDWs, including use of materials compatible with the injectate and native fluids. A well record review shall be performed for each well identified and, based on the results of the review, field inspection and testing of suspect wells should be performed. Wells should be assessed for internal and external mechanical integrity, corrosion, and integrity of cement plugs (in abandoned wells).
4) Performance of corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the injectate and native fluids, where necessary.
    a) Plugged and abandoned wells must be plugged in accordance with the standards in Appendix A. Wells not meeting these standards must be re-plugged.
    b) Wells that are not plugged and abandoned and that have not been used for injection or production for more than two years must be plugged in accordance with the standards in Appendix A.
    c) Remedial cementing and/or replacement or addition of casing, liner, tubing, or packer is required for active and idle wells if necessary to isolate all potential flow zones and to prevent the movement of fluids into or between USDWs or into any unauthorized zones.
    d) The Division may select any active, idle, or plugged and abandoned wells to be re-entered, examined, re-plugged and abandoned, or monitored to manage identified containment assurance issues prior to approval of injection.

(a)(1)(I)
We recommend the following revisions to this subsection:

"Maps of the locations of underground disposal horizons, enhanced oil recovery horizons, oil and gas producing zones, mining, and other subsurface industrial activities not associated to oil and gas production from the proposed injection project interval within the area of review."

(a)(2)
Given the Division's proposed revisions, there now appears to be overlap and possibly redundancy between subsections (a)(1)(B) and (a)(2). We request that the Division consolidate these two subsections, or clarify how they differ.

(a)(3)(C)
We recommend that the Division require the owner or operator of an injection project to prepare, maintain, and comply with a testing and monitoring plan to verify that the injection project is operating as permitted and is not endangering USDWs. The testing and monitoring plan should be submitted with the PAL, for the Division's approval, and should include a description of how the owner or operator will perform required monitoring, including accessing sites for all necessary monitoring and testing during the life of the project. Elements of the monitoring plan should include:

1. Yearly testing that will yield information on the chemical composition and physical characteristics of the injectate.
2. Monitoring of operational parameters (injection pressure, rate, and volume, the pressure on the annulus, and the annulus fluid volume) through the use of continuous recording devices.
3. Corrosion monitoring of injection well materials, required on a quarterly basis.
4. Monitoring of ground water quality and geochemical changes above the confining zone(s), at a site-specific frequency and spatial distribution.

5. External mechanical integrity testing, at least once per year.
6. Pressure fall-off testing, at least once every five years.
7. Testing and monitoring to track the extent of the injectate plume and the presence or absence of elevated pressure.
8. Any additional monitoring that the Division determines to be necessary to support, upgrade, and improve computational modeling of the AoR and to ensure that injection is not allowing the movement of fluid into USDWs.

(a)(3)(C)
We recommend the following revisions to this subsection:

(F) ~~Treatment of water to be injected.~~ A description of any physical or chemical treatments or processes performed on the injectate.

(a)(4)
The Division is proposing to allow operators to provide "representative step rate test data from select wells within the underground injection project in order to establish a conservative baseline fracture gradient for the entire area of the underground injection project. The Division will approve the use of an estimated baseline fracture gradient if, based on consideration of geologic, engineering, and operational factors, it is satisfied that the estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area."

Ensuring that injection does not initiate new fractures or propagate existing fractures in the injection zone(s), initiate fractures in the confining zone(s), or cause the movement of injection or formation fluids that endangers a USDW is a cornerstone of the UIC program. In order to achieve this, the fracture gradient of the injection and confining zones must be accurately known. The fracture gradient can vary across a field and therefore it is most protective to determine the fracture gradient in each injection well by performing a step rate test (SRT).

It is unclear how the Division will evaluate whether "estimated baseline fracture gradient is lower than the actual fracture gradient that would be encountered anywhere in the area" or how it will determine which SRTs are "representative" without detailed data on fracture gradients throughout the field. In its 2011 review, the Horsley Witten Group raised concerns about the Division's use of estimated fracture gradients based on empirical relationships, stating that, "Estimates of fracture pressures based on generalized relationships between fracture pressure and depth to the formation or other means are not always a reliable method for that determination." (Horsley Witten Group, 2011) The report commended the Division's recent directive requiring SRTs to be run in new wells, stating, "We support that directive to the fullest extent." (Horsley Witten Group, 2011)

The Division's proposal to allow the use of an estimated baseline fracture gradient appears to conflict with that directive and allow the continued use of a practice identified as potentially endangering USDWs. We therefore request that this provision be removed and all wells be required to perform an SRT.

(a)(5)
We request that the Division clarify what information is required to be contained in the "letters of notification," quantify the term "adjacent," and require notice to be given at least 30 days before commencement of injection and include proof of service.

(a)(6)
This provision contains a number of vague and undefined terms such as "large, unusual, and hazardous." We request that the Division clarify the intent of this section and/or define those terms.

(a)(7)
We recommend the following revisions to this subsection:

"Identification of all ~~injection~~ wells that are part of the underground injection project ~~and all production wells~~ or that are intended to be affected by the underground injection project, including but not limited to injection, production, observation, and monitoring wells.

(d)
This proposed subsection creates a potentially enormous loophole to the preceding requirements by allowing operators to submit alternative data when it is "infeasible" to submit the required data. The Division has provided no detail as to how it will determine whether or not submitting the required information is feasible or circumstances under which such an exemption would be appropriate. We request that the Division remove this proposed subsection.

1724.7.1. Casing Diagrams
We recommend that the casing diagram also include:

A. Owner's/operator's name
B. Lease name and number of the well
C. Date drilled
D. Date idled, if applicable
E. Date plugged, if applicable

1724.7.2. Injection Fluid Analysis
We recommend that benzene, toluene, ethyl benzene, and xylenes be added to the list of analytes in subsection (a).

We recommend that a new subsection (c) be added as follows:

(c) For Class IID disposal wells, injection fluid analysis required under this Article shall include testing to determine if the waste is a hazardous waste by sampling and testing the waste according to the methods set forth in California Code of Regulations, title 22, division 4.5, chapter 11, article 3 (section 66261.20 et seq.), or according to an equivalent method approved by the Department of Toxic Substances Control pursuant to California Code of Regulations, title 22, section 66260.21, except where the operator has determined that the waste is excluded from regulation under California Code of Regulations, title 22, section 66261.4 or Health and Safety Code section 25143.2. Notwithstanding any other section in this article, wastes that are determined by the operator to be hazardous wastes shall be managed in compliance with all hazardous waste management requirements of the Department of Toxic Substances Control.

1724.7.3. Step Rate Tests

(a)(1)
We recommend the following revisions to this subsection:

"When a step rate test is conducted on a formation with a permeability of greater than 10 millidarcies the well must be shut in ~~for at least~~ until the bottomhole pressures approximate shut-in formation pressures but not less than 48 hours prior to the test and the time steps shall be 60 minutes."

(a)(2)
We recommend the following revisions to this subsection:

"When a step rate test is conducted on a formation with a permeability of 10 millidarcies or less the well must be shut in ~~for at least~~ until the bottomhole pressures approximate shut-in formation pressures but not less than 72 hours prior to the test and the time steps shall be 90 minutes."

(a)(4)

Calculating fracture pressures based on surface pressure measurements can introduce significant error. The 2011 Horsley Witten Group report noted that most SRTs in California injection wells rely on surface pressure measurements and recommended that "the SRT should include a pressure gauge to measure bottom-hole pressures directly rather than relying on calculation of friction losses from surface pressure measurements and injection rates." (Horsley Witten Group, 2011) U.S. EPA also recommends the use of downhole pressure gauges during step rate tests. (U.S. Environmental Protection Agency, 1999) (U.S. Environmental Protection Agency, 2013) The Division has provided no guidance as to when an alternative to using downhole pressure gauges would be appropriate and we request that the Division remove this proposed exemption.

(a)(5)(b)

In addition to the listed data, operators should also report:

- Type and location of the pressure gauge;
- Type of flow meter and calibration records;
- Plot of flow rate versus pressure data; and
- Discussion of any anomalous data.

Recommended Additions

We recommend the following additions, consistent with U.S. EPA recommended procedures for SRTs (U.S. Environmental Protection Agency, 1999):

Injection rates should be controlled with a constant flow regulator that has been tested prior to use. A throttling device is not considered sufficient.

Flow rates should be measured with a calibrated turbine flowmeter.

Measure and record injection pressures with a gauge or recorder (for immediate test results). Record each time step and corresponding pressure.

A plot of injection rates and the corresponding stabilized pressure values should be graphically represented as a constant slope straight line to a point at which the formation fracture, or "breakdown", pressure is exceeded. The slope of this subsequent straight line should be less than that of the before-fracture straight line.

If the formation fracture pressure has definitively been exceeded, as evidenced by at least two injection rate-pressure combinations greater than the breakdown pressure, the injection pump can be stopped, and the line valve closed and pressure allowed to bleed-off into the injection zone. There will occur a significant instantaneous pressure drop (Instantaneous Shut-in Pressure or ISIP), after which the pressure values will level out. This ISIP value must be read and recorded. The ISIP obtained in this manner may be considered to be the minimum pressure required to hold open a fracture in this formation at this well.

Once the ISIP is obtained, the SRT is concluded.

In the event that the breakdown pressure was not obtained at the maximum test injection pressure utilized, the test results may indicate that the formation is accepting fluids without fracturing.

(c)

We recommend that the Division increase the notice time for a step rate test to 72 hours or 3 business days, whichever is greater, to allow for adequate time to respond to notices given over weekends.

1724.10. Filing, Notification, Operating, and Testing Requirements for Underground Injection Projects

(b)
We object to the Division's proposal to eliminate the requirement to submit a notice to convert an existing well into an injection well unless the well is reworked. The term "reworked" is undefined and this vagueness could lead to abuse. More importantly, however, the Division should not allow the conversion of wells to injection wells without Division review and approval. Existing wells are at greater risk for mechanical integrity issues and may not have been designed for the purpose of injection. Allowing operators to convert existing wells into injection wells without Division review and approval creates an unacceptable threat to USDWs. The existing requirement to submit a notice regardless of whether work is required on the well should be retained.

We recommend that the Division require notice to be given at least 30 days prior to commencement of drill, redrill, deepen, or rework and that activity should not proceed without written approval by the Division.

(d)
We request that the chemical analysis be performed at least yearly.

(e)
We request the following revisions:

The owner or operator must install and use continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the injectate; and the pressure on each annuli and annulus fluid volume ~~An accurate, operating injection pressure gauge or pressure recording device shall be installed whenever a well is injecting~~.

(g)
No exceptions should be made to the requirement that injection must occur through tubing set on a packer. Allowing injection to occur through the casing shortens the service life of and jeopardizes the integrity of the production casing by exposing it to potentially corrosive and erosive material and stress. This practice should cease.

We request that section (g) be replaced with the following:

All injection and production must occur through tubing on a packer set at a depth opposite a cemented interval at a location approved by the Division. Production and injection through the production casing or tubing-casing annulus is prohibited. The annulus between the tubing and production casing must be filled with a non-corrosive fluid compatible with the well construction materials and approved by the Division. The operator must maintain an annulus pressure that exceeds the pressure inside the tubing unless the Division determines that such a requirement might harm the integrity of the well.

(i)
We request that the Division use a safety factor of 90% rather than the proposed safety factor of 95%.

The Division's proposal to "approve a higher maximum allowable surface injection pressure based on a conclusive demonstration by the operator that the injected fluid will remain confined to the intended zone of injection" presents an unacceptable risk to USDWs and we request that this provision be dropped. The purpose of limiting the maximum allowable surface injection pressure (MASIP) is not only to ensure that injected fluid will remain in the injection zone but also to ensure that injection does not:

1. Initiate new fractures or propagate existing fractures in the injection zone(s);
2. Initiate fractures in the confining zone(s);
3. Compromise the mechanical integrity of the well; or,

4. Cause the movement of injection or formation fluids that endangers a USDW.[4]

This is a cornerstone of the UIC program. The Division has provided no explanation for why a higher allowable injection pressure should be permitted or how it will ensure USDWs are not endangered by such a practice.

(j)
Mechanical integrity tests (MIT) are used for two main functions: to ensure internal mechanical integrity (MI) and external MI. We therefore request the following revisions, consistent with federal UIC regulations[5]:

~~A m~~Mechanical integrity tests (MIT) must be performed on all injection wells to ensure: ~~the injected fluid is confined to the approved zone or zones.~~

1. There is no significant leak in the casing, tubing, or packer; and
2. There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.

An MIT shall consist of a two-part demonstration as provided in subsections subdivisions (j)(1) and (2).

(j)(1)
The U.S. EPA approved methods for demonstrating Part I internal mechanical integrity of Class II wells are the Standard Annular Pressure Test (SAPT), Standard Annulus Monitoring Test (SAMT), and the Radioactive Tracer Survey (RTS). (U.S. Environmental Protection Agency, 2008) The Division's proposed revisions to the Part I MIT do not comply with any of these test procedures. By eliminating reference to the tubing and tubing-casing annulus, the proposed revisions would appear to allow pressure tests to be conducted without the tubing and packer in place, in which case the test would not be able to demonstrate that the tubing and packer have integrity. The proposed rules also fail to specify the test duration or criteria that would indicate passage or failure of the test. We therefore request section (j)(1) be replaced with the following:

One of the following methods must be used to evaluate Part I internal mechanical integrity and the absence of significant leaks in the casing, tubing, or packer:

(a) Following an initial pressure test, owners or operators must continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume; or,
(b) Pressure test with liquid or gas initially, and subsequently no less than once per year and any time the tubing and/or packer are pulled from the well. The test procedure is as follows:
    a. The tubing/casing annulus (annulus) must be completely filled with liquid unless a variation is approved by the Division. Temperature stabilization of the well and annulus liquid is necessary prior to conducting the test. This may be achieved by filling the annulus with liquid and either ceasing injection or maintaining stabilized injection (i.e., continuous injection at a constant rate and constant injection fluid temperature) before and through the test. No unapproved substances may be added to the annulus liquid. Use of any substance which might affect the outcome of testing may constitute falsification of the test procedure, invalidate the test, and may subject the owner/operator to civil or criminal prosecution;
    b. After stabilization, the tubing-casing annulus should be tested at a pressure equal to the maximum allowed injection pressure, or the tubing pressure plus 200 psi, whichever is greater, unless an alternative test pressure is approved by the Division based on site-specific data.

[4] See, e.g. 40 CFR 146.23(a)(1), 146.67(a), and 146.88(a)
[5] See 40 CFR 146.8(a) *et seq.*

c. A successful test is one where the pressure stabilizes within 10% of the required test pressure and remains stable for a full 30 minute test period. A failed test is one in which the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak.
d. In the event of a failed test, the operator must:
    i. Orally notify the Division as soon as practicable but no later than 24 hours following the failed test, and;
    ii. Perform remedial work to achieve or restore mechanical integrity;
e. Injection may not begin or resume until a successful mechanical integrity test is performed and the results are submitted to the Division. If mechanical integrity cannot be achieved or restored, the well must be plugged and abandoned.

(j)(2)
The U.S. EPA approved methods for demonstrating Part II external mechanical integrity of Class II wells are Temperature Logs (TL), Noise Logs (NL), Oxygen Activation Logging (OAL), and Cement Records. (U.S. Environmental Protection Agency, 2008) The use of RTS for demonstrating Part II MI is only permissible in certain narrow circumstances, namely "where the underground source of drinking water directly overlies an injection zone separated only by an impermeable confining zone" – in other words, where there are no permeable formations between the injection zone and the lowermost USDW, just a single confining layer. (U.S. Environmental Protection Agency, 1987) As such, we request that proposed section (j)(2) be replaced with the following:

One of the following methods must be used to evaluate Part II external mechanical integrity and the absence of significant fluid movement into a USDW through channels adjacent to the injection well bore:

(a) A temperature or noise log; or,
(b) An approved tracer survey such as an oxygen-activation log.

The Division may allow the use of a radioactive tracer survey, in accordance with Section 1724.10.1, if the operator can demonstrate that the injection zone is separated from the lowermost USDW by a single, impermeable confining zone with no intervening permeable formations.

(j)(3)
We recommend that the Part II MIT be performed prior to injection and then at least yearly thereafter, with no exception. The Division has provided no justification for allowing operators to inject for three months before demonstrating the well has external mechanical integrity, and this proposed provision may endanger USDWs.

The Division's proposal to allow the second part of the MIT to be waived if the injection well is inactive is inconsistent with federal UIC Class II Guidance #78 for temporarily abandoned wells, which states that, "For wells temporarily abandoned in an "as is" condition, the owner/operator should continue monitoring and testing of the wells as required in his permit. This would include monitoring of annulus pressure (if required), injection pressure and flow rate ("zeros" on the reporting forms would allow the UIC Director to ascertain the TA status of the well). In addition, the operator must perform mechanical integrity tests as required by the permits [40 CFR 144.28(c)(2)(iv)(B)]," and "All monitoring and testing programs should remain in force until such time as the wells are either put back in service or properly plugged and abandoned." (U.S. Environmental Protection Agency, 1992) Additionally, the Part II MIT should be performed prior to the well being returned to service rather than three months after, as the Division is proposing.

The Division has provided no explanation for its proposed exemption from Part II MIT for "a cyclic steam well that has never injected more than 100 gallons per foot." Both internal and external MI testing are crucial for protecting USDWs and should not be waived.

In sum, we recommend the following revisions:

The second part of the MIT must be performed ~~within three (3) months after~~ prior to injection ~~has commenced~~. Thereafter, injection wells shall be tested at least once each year, or more frequently on a testing schedule approved by the Division based upon consideration of the age of the well, geology, and operational factors. Such testing for mechanical integrity shall also be performed following any significant anomalous rate or pressure change, or whenever requested by the Division. For temporarily abandoned or inactive wells, all monitoring and testing requirements will remain in force, including all required MI testing, until such time as the wells are either put back in service or properly plugged and abandoned. Both Part I and Part II MI testing must occur before recommencing injection. ~~The second part of the MIT is not required if the injection well is inactive, but shall be performed within three months after recommencing injection. The second part of the MIT is not required for a cyclic steam well that has never injected more than 100 gallons per foot.~~

(j)(4)
We recommend that:

1. The appropriate district office should be notified at least 72 hours before performing any MITs;
2. Copies of surveys and test results be submitted to the Division within 30 days, rather than 60 days.

(l)(4)
We recommend the following revisions:

(l) The operator shall cease injection into an injection well and shall not resume injection into the well without subsequent approval from the Division if any of the following occur:

(4) There is any indication of that damage to life, health, property, or natural resources, or loss of hydrocarbons is occurring, has occurred, or has become likely to occur by reason of the project;

(l)(6)
We recommend that the Division add a provision requiring operators to report when a well becomes inactive and a subsequent yearly status report until the well is either put back into service or permanently plugged and abandoned, in order to better enable the Division to ascertain when two years have passed.

1724.10.1. Mechanical Integrity Testing
We recommend the following additions to this section:

(c) A noise log performed under Section 1724.10(j)(2) shall adhere to the following:

(1) Noise logging may be carried out while injection is occurring. If ambient noise while injecting is greater than 10 mv, injection should be halted.

1724.11. Incident Response
We recommend the following revisions to this section:

(a) For the purposes of this section, "reportable incident" means any of the following:

(1) Any failure of mechanical integrity including but not limited to:

(A)~~(2)~~ A mechanical integrity test indicates that an injection well lacks integrity or is otherwise incapable of performing as approved by the Division;

(B)~~(3)~~ A failure, breach, or hole in the well tubing or packer;

(C)~~(4)~~ A failure, breach, or hole in the well casing, including failures above and below a packer;

(D) A failure, breach, or hole in the well cement;

(2)~~(5)~~ The migration or movement of any amount of injection fluid to an unpermitted zone; ~~or~~

(3) Any triggering of an automatic shutoff system (surface or down-hole);

(4) Any noncompliance with a permit condition or malfunction of the injection system which may cause fluid migration into or between USDWs; or,

(5)~~(6)~~ Any other incident or occurrence that indicates fluid is not or may not be confined to the approved injection zone, or that indicates the injection well threatens human health, public safety or the environment or endangers a USDW.

(b) In the event of a reportable incident, the operator of the well must notify the appropriate district office immediately upon discovering the reportable incident. The operator shall consult and share information with the Division. Public notice shall also be provided on the Division's website and to landowners, residents, and offset operators within 1 mile of the injection project boundary.

(c) The operator shall comply with all operational and remedial directives of the Division, including but not limited to ceasing injection operations at the well(s) in question.

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Appendix I: Well Plugging Requirements

1.0 General Plugging Requirements.

(a) Wells shall be plugged to ensure that all formations bearing protected water, hydrocarbons, or geothermal resources are protected, confined to their respective indigenous strata and are prevented from migrating into other strata or to the surface.

(b) All cementing operations during plugging shall be performed under the direct supervision of operator or its authorized representative, who shall be independent of the applicable service or cementing company hired to plug the well. Operator and the cementer shall both be responsible for complying with general plugging requirements and for plugging the well in conformity with the procedure set forth in the approved application to plug and abandon the well.

(c) Cement plugs shall be set to isolate each hydrocarbon strata and the lowermost protected water strata. Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by the Division. Operator shall verify the placement of the plug required at the base of the deepest protected water stratum by tagging with tubing or drill pipe or by an alternate method approved by the Division.

(d) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe, subject to approved exceptions by the Division.

(e) All cement used for plugging shall be of a composition approved by the Division, and the Division may require that specific cement compositions be used in certain situations. Cement must conform to API Specification l0A (Specification for Cement and Material for Well Cementing). the Division may require additional cement additives or cement in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or provide safer conditions in the well or the area around the well. the Division may approve the use of alternate materials if the Division deems it appropriate, but the Division shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources. Operator must follow all other quality control and quality assurance requirements for cement installation listed in Article IV.

(f) The Division may require additional cement plugs to cover and contain any hydrocarbon stratum, or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and respotting is required to ensure that the well does not pose a potential threat of harm to natural resources.

(g) A 50-foot cement plug shall be placed in the top of the well, and casing shall be cut off at least three feet below the ground surface or at such other depth as required by the Division.

(h) Mud-laden fluid of at least 9.0 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by the Division. The mud-laden fluid must exert a fluid density greater than the highest formation pressure in the interval between the plugs at the time of abandonment. The hole shall be in static condition at the time the cement plugs are placed. The Division may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will ensure that the well does not pose a potential threat of harm to natural resources, public safety, or the environment. The Division may approve the use of alternate fluid if the Division deems it appropriate, but the Division shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources, public safety, or the environment.

(i) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except as may be otherwise expressly permitted under law. Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by the Division.

(k) Operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, operator shall remove all such tanks, vessels, and related piping, remove all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. Operator shall close all pits in accordance with applicable the Division requirements. The Division may grant an extension of not more than an additional 60 clays for the removal of tanks, vessels and related piping.

(l) Operator must notify the Division at least 24 hours prior to commencing plugging and well abandonment operations.

(m) Operator shall complete and file with the Division a duly verified plugging record, in duplicate, on a form approved by the Division within thirty (30) clays after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

(n) The Division will witness the work, review the 30 day plugging records, and will issue a plugging and abandonment approval within 30 clays, or issue a corrective action order. Corrective action must be completed within the timeframe specified in the order, but no later than 30 days from the date of the order. The Division may require surface and/or subsurface monitoring programs after the well has been plugged and abandoned, if there is any reason to believe that subsurface or surface pollution occurred or may persist. The Division reserves the right to require the operator to re-enter the well and complete additional remediation or plugging and abandonment work in the future, so long as operator has the legal right to enter upon the leased premises to conduct such operations.

1.1 Plugging Requirements for Wells with Surface Casing.

(a) When insufficient surface casing was set to protect all protected water strata and all hydrocarbon strata, and such strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug or plugs shall be placed centered opposite the top of each hydrocarbon stratum and the base of the deepest protected water stratum. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the top of each hydrocarbon stratum or abnormally geo-pressured strata, and the base of the deepest protected water stratum. The plug across the deepest protected water stratum shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug or plugs shall be set across the shoe of the surface casing and any multi-stage cementing tool. Each such plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above and below the shoe or multi -stage cementing tool.

(b) When sufficient surface casing has been cemented to isolate all protected water, a cement plug shall be placed across the shoe of the surface casing and across any multi-stage cementing tool. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above the shoe and at least 100 feet below the shoe.

(c) If surface casing has been set deeper than 200 feet below the base of the deepest protected water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest protected water stratum. This plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the base of the deepest protected water stratum.

(d) Plugs shall be set as necessary to separate multiple protected quality water strata by placing the required plug at each depth as determined by the Division.

1.2 Plugging Requirements for Wells with Intermediate Casing.

(a) For wells in which the intermediate casing has been cemented through all protected water strata and all hydrocarbon strata, a cement plug or plugs meeting the requirements of Section 1.1(a) shall be placed inside the casing and centered opposite the base of the deepest protected water stratum, but extend no less than 50 feet above and below the base of the deepest protected water stratum. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest protected water stratum. In addition, a cement plug or plugs shall be set across the shoe of the intermediate casing, if it is open to the wellbore, and any multi-stage cementing tool. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe or multi-stage cementing tool, as applicable.

(b) For wells in which intermediate casing is not cemented through all protected water strata and all hydrocarbon strata, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through casing perforations.

(c) Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by the Division.

1.3 Plugging Requirements for Wells with Production Casing.

(a) For wells in which the production casing has been cemented to isolate all protected water strata and all hydrocarbon strata, and a cement evaluation tool has been run and the cement is verified to be in good condition and determined to be a barrier to fluid and gas migration in the annulus, a cement plug meeting the requirements of Section 1.1(a) shall be placed inside the casing and centered opposite the top or the uppermost hydrocarbon stratum and the base of the deepest protected water stratum and across any multi-stage cementing tool. If annular cement integrity cannot be confirmed, the Division will require the annulus to be squeeze cemented. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the top of the uppermost hydrocarbon stratum and the base of the deepest protected water stratum.

(b) For wells in which the production casing has not been cemented through all protected water strata and all hydrocarbon strata and if the casing will not be pulled, the production casing shall be perforated at the required depths to place cement outside of the casing by squeeze cementing through the casing perforations.

(c) The Division may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

(d) Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by the Division.

1.4 Plugging Requirements for Wells with Screen or Liner.

(a) The screen or liner shall be removed from the well, unless determined by the Division to be technically infeasible.

(b) If the screen or liner is not removed, a cement plug in accordance with Section 1.1(a) shall be placed at the top of the screen or liner.

1.5 Plugging Requirements for Wells with Formation Pressure Problems.

(a) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in Section 1.1(a) above.

(b) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation and abnormally geo-pressured strata, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

1.6 Plugging Horizontal Wells.

All plugs in horizontal wells shall be set in accordance with Section 1.1(a). The productive horizon isolation plug shall be set from a depth of 50 feet (measured depth) below the top of the productive horizon to a depth of either (i) 50 true vertical feet above the top of the productive horizon, or (ii) if the production casing is set above the top of the productive horizon, 50 true vertical feet above the production casing shoe. In accordance with Section 1.0(f), the Division may require additional plugs.